

MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills 26R Storage Project

Injection Zone Monitoring Well 341-27R

Facility Information

Facility Name: Elk Hills 26R Storage Project
341-27R

Facility Contact: Travis Hurst / Geological Advisor
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CP Details_341- 27R	1	12/20/22	Original document, combines well construction, operating procedures, and plugging plan into monitoring well narrative document.

Introduction

CTV requires four monitoring wells for the Elk Hills 26R Storage Project. CTV intends to repurpose three existing wells for monitoring the injection interval and one existing well for above zone monitoring. Figure 1 identifies the wells proposed for the project. This document describes the construction, logging, testing, and plugging plans for injection zone monitoring well 341-27R.

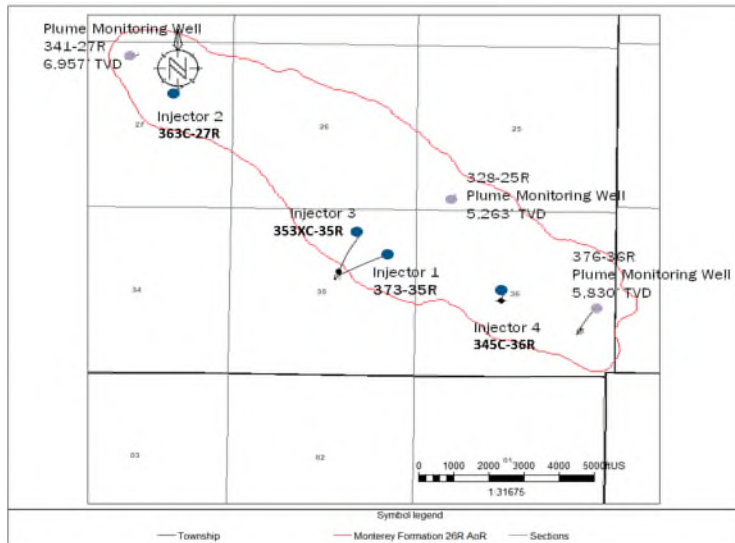


Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 341-27R is an existing oil and gas production well that was drilled in 1975 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be reused for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention

341-27R was drilled in 1975, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors.
2. Although no USDW is present, multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing.
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement, and each casing string was cemented to surface.
4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the injection zone and consistent with cementing operations results. Cement is present above the top of the injection zone (~6957') in the CBL

logging interval within the Monterey formation and across the Reef Ridge formation (from base of 7" casing to ~6600 feet).

5. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted.
6. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
7. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous injection conditions.
8. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.

Materials

Well materials utilized will be compatible with the CO₂ injectate and will limit corrosion:

- Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Packer – corrosion resistant alloy material or coating and hardened rubber elastomer element material.
- Casing – the standard K-55 casing which is currently installed will be demonstrated to be compatible with the CO₂ injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
- Cement- portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO₂ when good cement bond between formation and casing exists within the Injection and Confining Zones.

Standards

Well materials follow the following standards:

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock

3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Casing

The Monterey Formation temperature in 26R is approximately 210 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Temperature differences between the CO₂ injectate and reservoir will not affect well integrity. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the reservoir conditions associated with maintaining annular fluid and pressure. The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

Table 1: Casing Specifications for the 341-27R injector

Name	Depth Interval (feet)	Hole Section Diameter (inches)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)
Conductor	12' - 52'	24	20	19.124	94	-	-	2.62	-
Surface	12' - 506'	17.5	13.375	12.615	54.5	K-55	Short	2.62	2730
Intermediate	12' - 2757'	12.25	9.625	8.835	40	K-55	Long	2.62	3950
Long-string	12' - 38'	8.75	7	6.276	26	K-55	Long	2.62	4980
	38' - 5318'			6.366	23				4360
	5318' - 7333'			6.276	26				4980

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

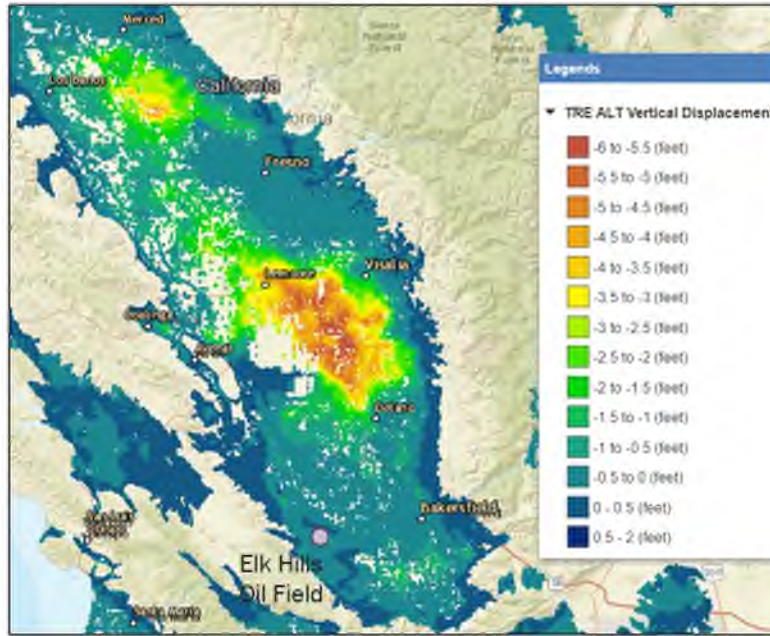


Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (<https://sgma.water.ca.gov/>).

Cement

Class G portland cement has been used to cement the well. This cement is widely used in CO₂-EOR wells and has been demonstrated to have properties that are not deleterious with CO₂. The 13-3/8" casing string was cemented with returns to surface. The 9-5/8" casing string was cemented with returns to surface. The 7" casing string was cemented in place with Class G portland cement. Subsequently, a CBL was run from 5785' – 7285' and indicates annular isolation throughout and above the Monterey and into the Reef Ridge formations.

Tubing and Packer

The information in the tables provided in Table 2 and Table 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications may be modified prior to conversion during pre-operational testing.

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. An appropriate grade of material will be installed based on the CO₂ injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	6950'	2.875	2.441	6.5	L-80 CRA	Premium	10,570	11,170

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the long-string casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	6920'	30.2	23 - 32	5.687	3.25

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.366	6.049

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The wellhead tree will include redundant master valves and wing valves, and the valves will remain closed during normal injection operations. Safety valves or other automatic shut-off devices are not required for monitoring wells, in general. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided in the following discussion. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
341-27R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	<i>Internal MI:</i> SAPT	Casing/tubing annulus above packer
	<i>External MI (at least one of):</i> Oxygen Activation Log Noise Log	Along the 7" casing to surface

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from 2,800' feet measured depth (MD) to bottom hole at 9,885 feet MD (Table 5).

Table 5: Deviation checks during drilling for the 341-27R well.

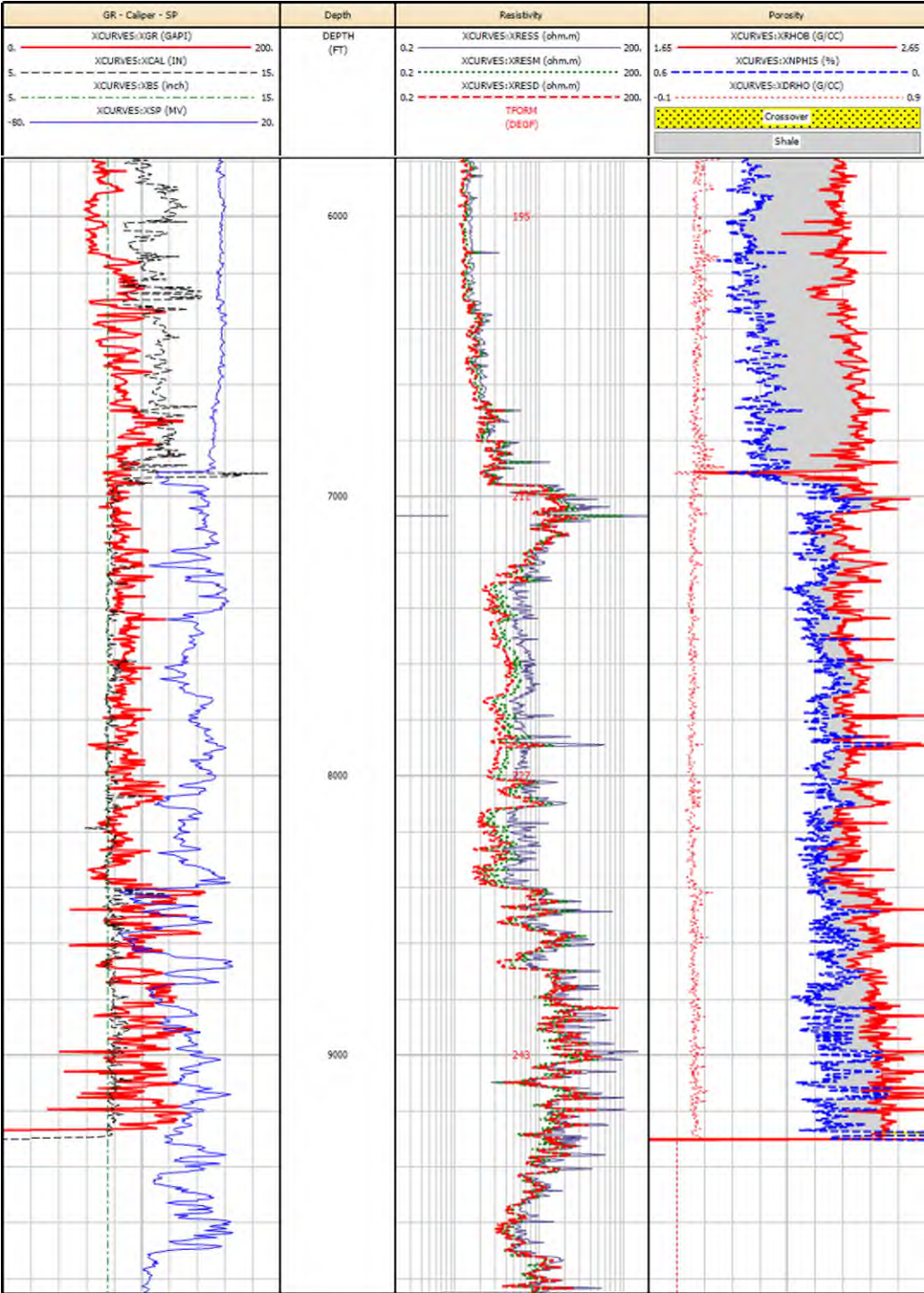
MD	INC	AZI	TVD		MD	INC	AZI	TVD
0	0	0	0		6400	1.6	106.98	6399.2
2800	1.3	158.98	2799.8		6500	1.9	104.98	6499.1
2900	1.4	170.98	2899.7		6600	2.6	97.98	6599.1
3000	1.5	171.98	2999.7		6648	2.8	92.98	6647
3100	1.3	165.98	3099.7		6704	3.1	90.98	6702.9
3200	1	170.98	3199.7		6800	3.6	85.98	6798.8
3300	0.7	175.98	3299.6		6900	4.1	79.98	6898.6
3400	0.7	170.98	3399.6		7000	3.9	88.98	6998.3
3500	0.7	151.98	3499.6		7100	3.8	88.98	7098.1
3600	0.8	134.98	3599.6		7200	3.7	90.98	7197.9
3700	0.8	137.98	3699.6		7300	3.7	88.98	7297.7

3800	0.7	134.98	3799.6		7400	3.5	100.98	7397.5
3900	0.7	119.98	3899.6		7500	3.1	98.98	7497.3
4004	0.4	136.98	4003.6		7600	3.3	107.98	7597.1
4100	0.5	1.98	4099.6		7704	2.3	111.98	7701
4200	0.7	300.98	4199.6		7800	2.4	111.98	7796.9
4300	0.8	302.98	4299.6		7904	2.6	99.98	7900.8
4400	0.9	304.98	4399.6		8000	2.9	102.98	7996.7
4500	1	329.98	4499.5		8100	2.3	92.98	8096.6
4600	1.2	320.98	4599.5		8200	2.7	80.98	8196.5
4700	1.1	314.98	4699.5		8300	2.7	86.98	8296.4
4800	0.8	349.98	4799.5		8400	2.7	85.98	8396.3
4900	0.7	32.98	4899.5		8500	3.6	79.98	8496.2
5000	0.8	62.98	4999.5		8600	3.5	69.98	8596
5100	1.2	73.98	5099.5		8700	3.4	68.98	8695.8
5200	1.1	90.98	5199.4		8800	4	66.98	8795.6
5300	1.1	99.98	5299.4		8904	4.6	73.98	8899.3
5400	1.3	113.98	5399.4		9000	6.3	75.98	8994.8
5500	1.2	119.98	5499.4		9100	7.1	70.98	9094.2
5600	1	127.98	5599.4		9200	8	75.98	9193.3
5704	0.9	157.98	5703.3		9292	8.2	77.98	9284.4
5800	1.1	129.98	5799.3		9400	11.9	26.98	9390.9
5900	1	150.98	5899.3		9500	9.9	60.98	9489.2
6000	1.2	133.98	5999.3		9600	10.2	59.98	9587.7
6100	1.3	112.98	6099.3		9700	11.2	54.98	9685.9
6200	1.3	117.98	6199.2		9800	12.7	59.98	9783.7
6300	1.3	111.98	6299.2		9885	13.1	55.98	9866.6

Open Hole Log Analysis

Open-hole wireline log data was acquired prior to installation of 7” casing long string. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (middle), neutron porosity and bulk density in track 3 (right most).

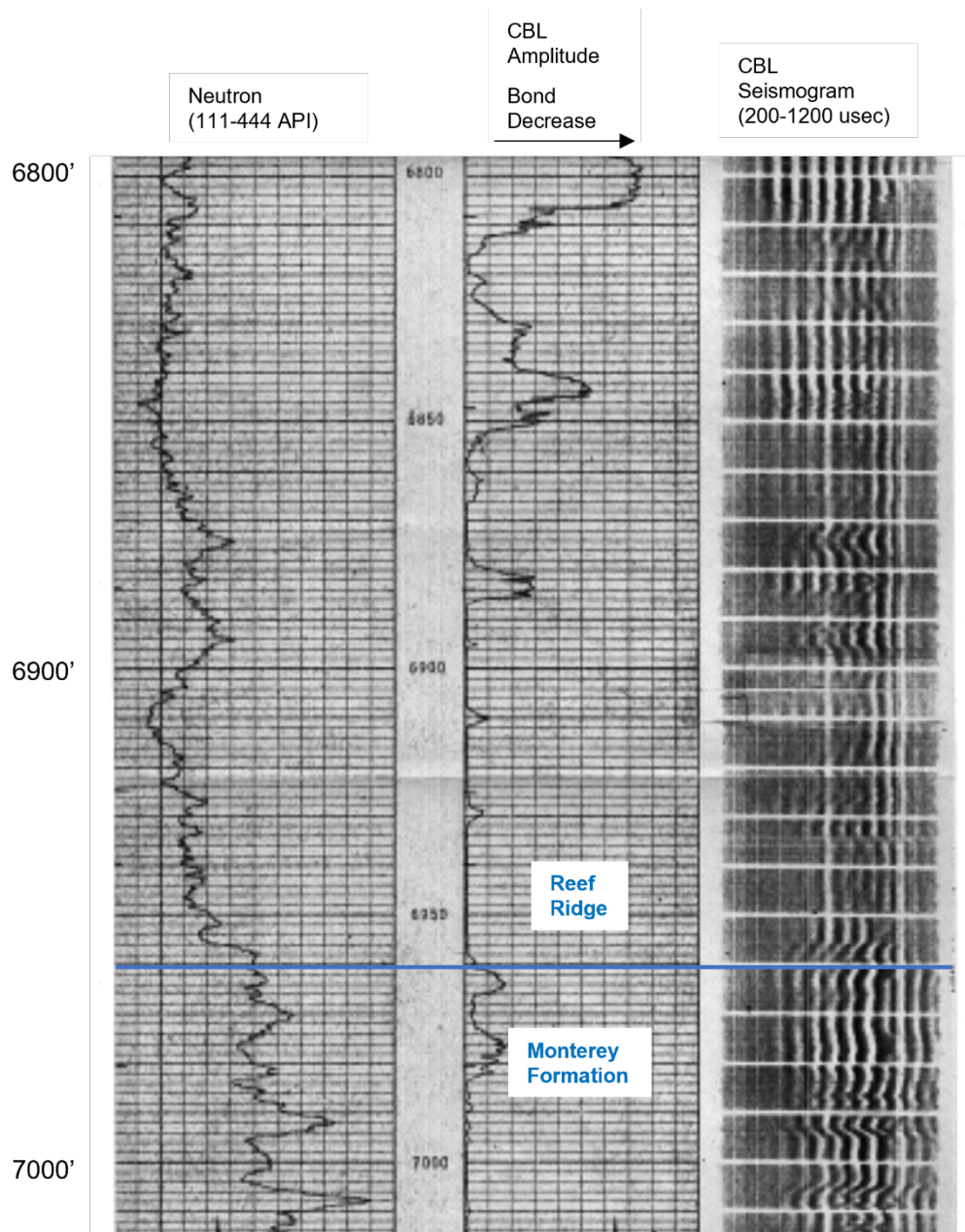
Figure 3: Open-hole well logs for 341-27R before installation of long string.



Cement Evaluation

The cement bond log amplitude and sonic seismogram show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 2). Late seismic signal arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was not logged across the entire 7" casing interval. The top of cement was observed around 6600' MD, the top of the cement bond logging interval was 5785' MD. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing.

Figure 4: Cement bond log example for 341-27R, after installation of long string casing. The Monterey Formation 26R top is at 6,957 feet.



MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

Planned Well Retrofitting

Prior to first injection, the existing wellbore will be reconfigured for injection through the following procedure:

1. Install and test Blowout Prevention Equipment (BOPE)
2. Pull existing injection tubing and packer
3. Clean out well to Plugback Measure Depth (PBMD)
4. Acquire remaining pre-operational phase data per Att G and T&M docs
5. Install CCS injection tubing, packer, injection tree, and all monitoring equipment per T&M and well schematics.
6. Perform Standard Annular Pressure Test (SAPT) per T&M procedure
7. Suspend well temporarily for CCS project startup

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature profile, which could be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO₂. Deviations between the temperature log performed before, during, and after injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO₂ into and within the wellbore. This cement is widely used in CO₂-EOR wells and has been demonstrated to have properties that are not deleterious with CO₂.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 12' MD due to the depth reference to the kelly bushing 12' above ground level during drilling.

Table 6: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.276	6.366	6.366	6.276
Depth to bottom of tubing or drill pipe (ft)	7,287	2,414	1,018	37

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Sacks of cement to be used (each plug)	83	25	25	5
Slurry volume to be pumped (ft ³)	96	29	29	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	6,845	2,289	893	12
Bottom of plug (ft)	7,287	2,414	1,018	37
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.
2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO₂ in the wellbore. If CO₂ were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.
3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.
5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.
6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.
7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.
8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):
 - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.
 - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.